From Mineralogy to Mechanical Properties: integrating core data and rock physics simulations for stiffness tensor estimation in Vaca Muerta organic-rich mudrock

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SUMMARY

From a mechanical perspective, organic mudrocks are viscoelastic media whose anisotropy can be accurately represented using a vertical transverse isotropy (VTI) model. These reservoirs exhibit ultra-low permeability, typically in the range of nano to microdarcies, and possess a complex pore structure. Such characteristics, along with different oil, gas and water fluids saturations, significantly impact the hydraulic properties and mechanical behavior of the reservoir during production. This study introduces a practical methodology to estimate the stiffness tensor of dry rock using theoretical models of rock physics, incorporating mechanical, mineralogical, and petrophysical data from a core extracted from the lower section of the Vaca Muerta Formation (VMF), located in the Neuquén Basin, Argentina. This core was extracted from a block located in the maximum oil generation window of the Vaca Muerta formation at a depth of 3100 m. The dry-rock stiffness tensor is initially computed and validated against laboratory phase velocity measurements at 1 MHz, showing discrepancies below 10 percent. The synthetic sample is subsequently saturated with hydrocarbon fluids to evaluate attenuation and dispersion effects associated with wave-induced fluid flow (WIFF) and the resulting mode conversions. Fluid-saturated simulations reveal that phase velocities decrease markedly with increasing gas content, with frequency variations depending on the fluid mixture, particularly above 100 Hz. Patchy gas-oil saturation yields higher velocities than uniformly mixed fluids, while exhibiting significantly greater attenuation due to enhanced WIFF. The frequency-dependent peak attenuation shifts toward lower frequencies in patchy cases, in agreement with mesoscopic pressure diffusion theory. These results emphasize the critical role of fluid composition and spatial distribution in seismic velocity and attenuation in unconventional reservoir characterization.

INTRODUCTION

The objective of this study is to apply the two-dimensional numerical model —a physically grounded, non-phenomenological formulation based on Biot's theory of poroelasticity to investigate the anisotropic poroelastic response of the Vaca Muerta Formation (VMF), an organic-rich marlstone situated in the Neuquén Basin, Argentina, under variable fluid saturation conditions and seismic range of frequencies.

As a basis for the numerical modeling, we employ the rock physics theory which integrates mineralogical and petrophysical data from a core sample extracted from the VMF. This approach enables the estimation of the dry bulk modulus K_m and shear modulus μ_m of the multi-mineral porous matrix. Then, the VMF is assumed to consist of a sequence of very thin horizontal layers composed of kerogen (as the primary organic constituent) and mineral aggregates, within which Biot's theory in the diffusive frequency range is applicable.

At long wavelengths compared with the average layer thickness VMF behaves as a transversely isotropic anisotropy with a vertical axis - VTI.

To determine the p_{ij} stiffness coefficients of the equivalent VTI medium, a set of five boundary value problems (BVPs) based on Biot's diffusive equations are formulated in the space–frequency domain. Each BVP defines a compressibility or shear test, which is solved numerically using the Finite Element (FE) method across a range of relevant frequencies.

These tests are first applied to a dry synthetic sample to compute the stiffness tensor and derive the corresponding dry-rock phase velocities. The simulated phase velocities exhibit very good agreement with laboratory measurements, with discrepancies remaining below 10 percent.

Following the dry-rock analysis, the synthetic sample is saturated with gas, oil, and water to investigate attenuation and dispersion effects associated with mode conversions caused by wave-induced fluid flow (WIFF).

Additionally, the case of patchy gas–oil saturation is examined and compared against scenarios of uniform saturation, in order to evaluate the effects of fluid distribution on seismic velocity and attenuation.

RESULTS

Data

A dry core from the Vaca Muerta Formation is the source of the measured data, which consist of rock mineralogy and phase velocities, vp_{11}, vp_{33}, vp_{55} and vp_{66} of the core at 3100 m depth. This core corresponds to the window of maximum oil generation in the formation; its location is marked with a red rectangle in Figure 1.

To estimate of the elastic tensor coefficients p_{ij}, we assume that VMF consists of a periodic alternation of two porous materials, each with a porosity of 6 percent and $2.75 \ 10^{-18} \ m^2$

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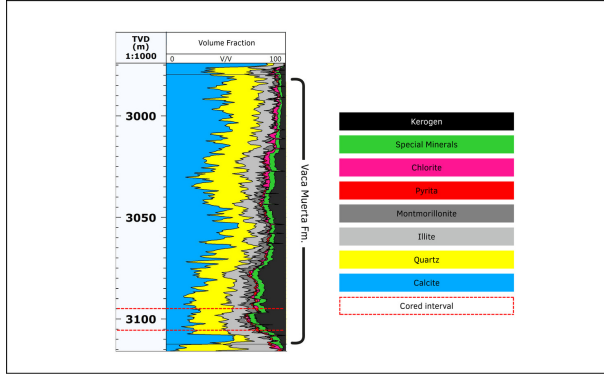

Figure 1: Location of the core area, marked with a red rectangle. The green region corresponds to the the oil-generating window in the Vaca Muerta formation.
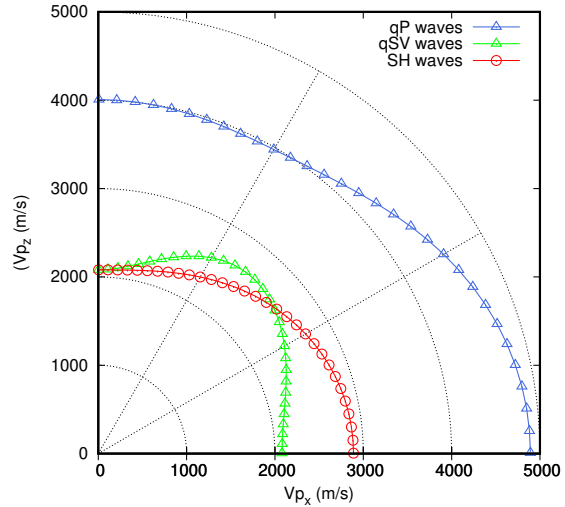

Figure 2: Polar representation of phase velocities of qP, qSV and SH waves at 1 MHz. The medium consists of a periodic sequence of forty nine dry layers of the composite porous solid including kerogen as a mineral with 23 % proportion, and one dry kerogen layer.

Figure 2-3 shows polar representation of phase and energy velocities of *qP*, *qSV* and *SH* waves of the dry core at 1 MHz. Anisotropy is clearly observed in the behavior of the velocities of the three wave modes.

permeability.

Material 1 is composed of seven minerals, including 23 % kerogen, 37.27 % Clay, 14.61 % Quartz, 10.68 % Calcite, 2.57 % Plagioclase, 2.37 % Dolomite and 3.5 % Pyrite. Using the solid grains density, bulk and shear moduli of each mineral and a generalized Krief model (see Carcione et al, Geophysics,2005), we obtained the values K_s, K_m, μ_m for the dry core as shown in Table 1 as well as its average density

Besides, the single layer of Material 2 consists of dry kerogen. Its properties can be seen in Table 1

The harmonic simulations were performed on a representative dry square sample with a side length of 2 mm, consisting of four repetitions of a periodic sequence composed of 49 layers of Material 1 and one layer of Material 2 per period. Each layer has a uniform thickness of 10^{-5} m. The computational domain was discretized using a 200×200 mesh.

Phase velocities and attenuation using using hydrocarbon saturated samples

Figures 4 and 5 present the phase velocity and attenuation behavior of qP wave waves traveling normal to the bedding, denoted as '33' waves' (p_{33} mode) under four fluid saturation scenarios: 100 percent oil, 100 percent gas, 10 percent gas plus 90 percent oil, and a ternary fluid mixture consisting of 40 percent gas, 52 percent oil, and 8 percent water, obtained from the well's fluid saturation log at the depth corresponding to the core sample.

The corresponding attenuation factors 1000/Q33 (Q3 i sthe quelity factor) are displayed in Figure 9. Note that '33' waves exhibit more attenuation and the attenuation peaks are shifted to higher frequencies when the saturant fluid is gas.

Table 1. Properties of Materials

Property	Material 1 (Composite)	Material 2 (kerogen)
K_s (GPa)	56.14	7.0
K_m (GPa)	29.19	1.29
μ_m (GPa)	17.78	0.36
ρ (kg/m^3)	2487	1400

Computed VTI phase velocities using the dry-core data

Since the phase velocity data corresponds to a dry sample, the numerical experiment consider air as the saturating fluid. Table 2 summarizes the results of the VTI experiments.

PATCHY SATURATION

To consider fractal variations of gas and oil saturations we use the von Karman self-similar correlation function.

Table 2. Phase velocities computed, measured and error percentage.

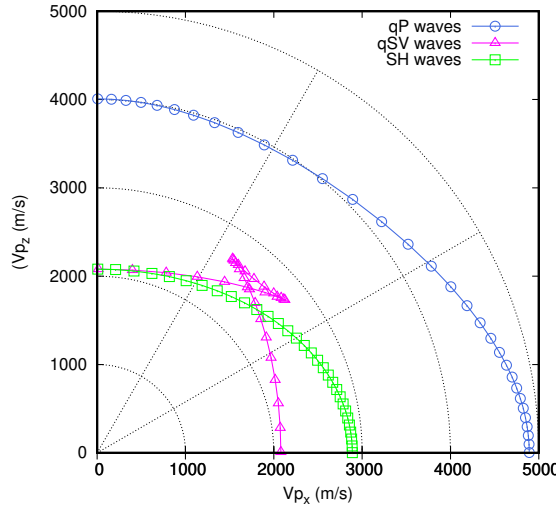| Phase velocity vp (m/s)	Computed	Measured	Percentage error
v11	4644.37	4331	7.2 %
v33	3804.51	4217.47	9.8 %
v55	1974.76	2193.61	9.9 %
v66	2742.64	2581	6.2 %

Figure 3: Polar representation of energy velocities of qP, qSV and SH waves computed using the FE method. Frequency is 1 MHz.
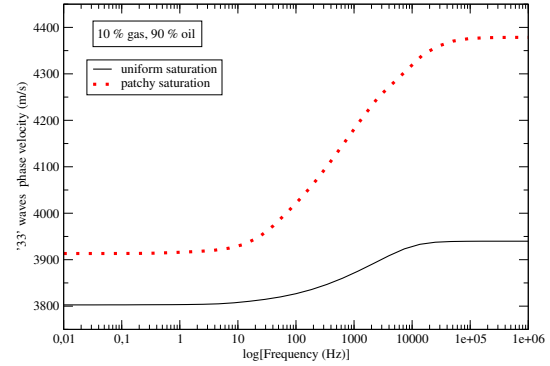

Figure 5: Phase velocity of '33' waves as function of frequency for 10 % gas, 90 % oil and uniform and patchy saturation.
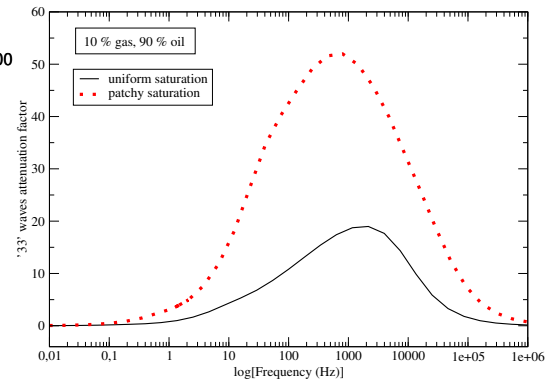

Figure 6: Attenuation factor of '33' waves as function of frequency for 10 % gas, 90 % oil and uniform and patchy saturation.
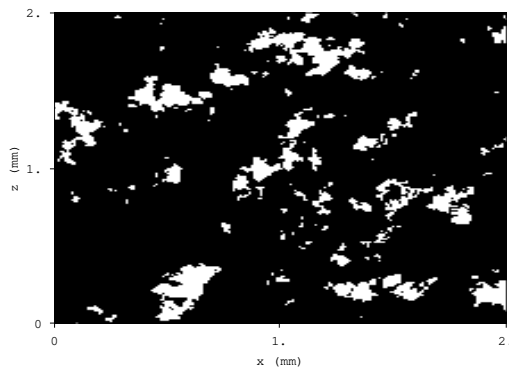

Figure 4: Fractal patchy gas-oil spatial distribution. White zones correspond to full gas saturation and black regions to full oil saturation, with overall gas saturation 10 percent. Fractal dimension is 2.4, correlation length is 0.09 mm.

In Figure 5 the uniform case assumes perfect mixing at the pore scale, producing a single-phase effective fluid with increased compressibility, resulting in lower velocities. In contrast, the patchy case consists of spatially segregated gas- and oil-filled regions. Wave propagation is governed by the stiffer oil-saturated zones, leading to higher velocities across the frequency spectrum. The divergence between the two models becomes particularly evident above 100 Hz, consistent with mesoscopic WIFF activation.

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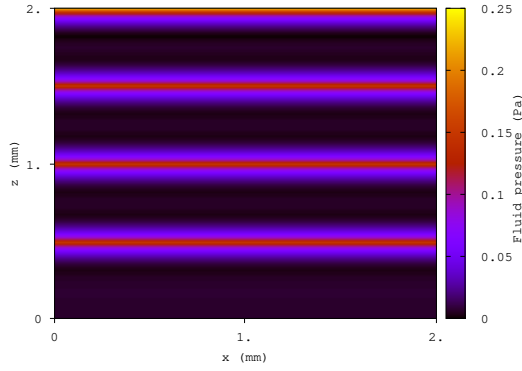

Figure 7: Fluid pressure for the case of 10 % gas, 90 % oil and uniform saturation.
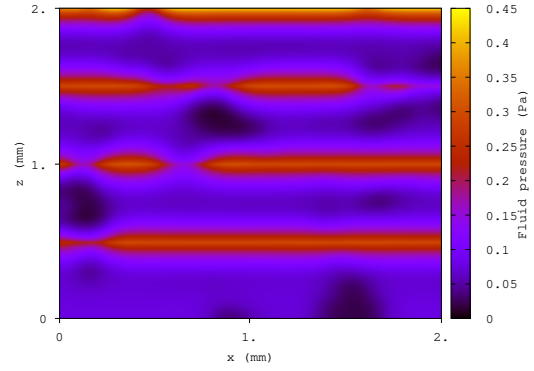

Figure 8: Fluid pressure for the case of 10 % gas, 90 % oil and patchy saturation.

Patchy saturation in Figure 6 results in markedly higher attenuation due to enhanced WIFF at gas– oil interfaces. These effects promote localized pressure gradients and viscous fluid movement, leading to increased energy dissipation. Additionally, the attenuation peak is shifted to lower frequencies under patchy saturation, reflecting the longer diffusion times associated with larger- scale heterogeneities and limited pressure communication between fluid patches.
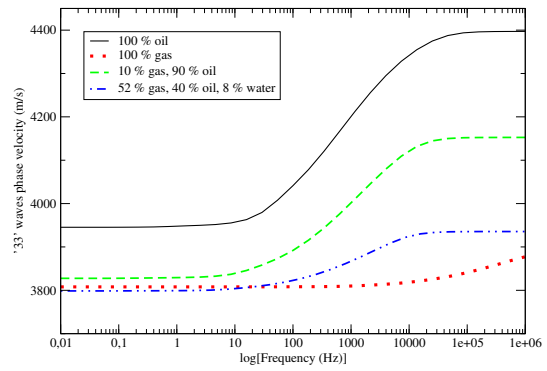

Figure 9: '33' waves phase velocity as function of frequency.

CONCLUSIONS

We have presented a rock physics simulation-based methodology for estimating the stiffness tensor of a dry core sample from the Vaca Muerta formation in Neuquén, Argentina, using mineralogical characterization as input data. The proposed methodology was tested by comparing the numerical phase velocities with those measured in laboratory at 1 MHz, yielding excellent agreement. Furthermore, the procedure can be applied to study the influence of fluid saturation and different source frequencies at laboratory and field scales.
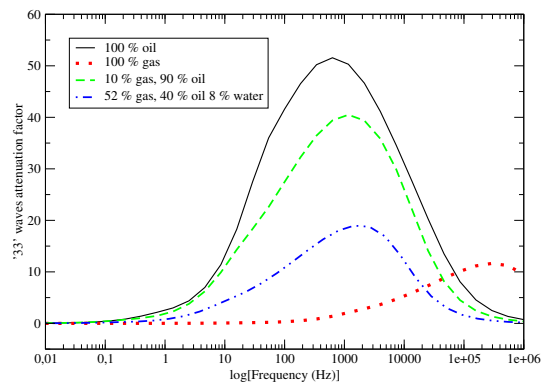
Figure 10: Attenuation factor 1000/Q as function of frequency for '33' waves.